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Application of Experimental Design and Response Surface Methods in Probabilistic Geothermal Resource Assessment: numerical simulation and volumetric methods

Jaime Jose Quinao* and Sadiq J. Zarrouk

Department of Engineering Science, University of Auckland, Private Bag 92019, Auckland 1142, New Zealand

*jaime.quinao@mightyriver.co.nz

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ABSTRACT

Resource estimates in geothermal "green" fields involve significant inherent uncertainty due to poorly constrained subsurface parameters and multiple potential development scenarios. There is also limited published information on probabilistic resource assessments of geothermal prospects. This paper explores the applications of a systematic experimental design (ED) approach to a geothermal reservoir simulation model to generate probabilistic resource assessment results.

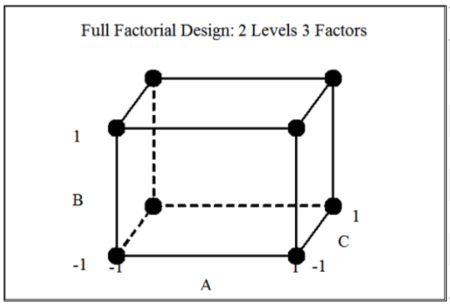
A Plackett-Burmann design was used to build 12 simulation experiments for a geothermal system, investigating six model parameters at two levels. A probabilistic 30-yr power capacity was successfully generated from the resulting response surface. Analysis of the response also showed that the power capacity was significantly affected by only three of the tested parameters: reservoir temperature, permeability, and well depth. Volumetric methods, both "heat in place" and mass in place, were applied to the same modelled system to compare the resource assessment results.

Applying the experimental design (ED) and response surface methodology (RSM) enables the use of geothermal reservoir simulations for probabilistic geothermal resource assessments. The assessment using volumetric heat in place methods, even with similar thermal recovery factors, still results in variations due to differences in conversion of recovered thermal energy at the wellhead to electrical power capacity. It is recommended that the conversion efficiencies be carefully considered and the assumptions clearly stated when translating recovered thermal energy into electrical capacity. Noting the uncertainties in the thermal recovery factor, it is also recommended that production-based methods using numerical simulation or volumetric mass in place be used to estimate electric power capacities.

1. INTRODUCTION

Experimental design (ED) or design of experiments is a systematic way of simultaneously testing multiple variables that affect a response. The application of this methodology to geothermal reservoir simulations and consequently, reservoir simulation-based probabilistic resource assessment, is the objective of this study.

To illustrate, let us take for an example a reservoir simulation as an experiment where total flow response to three parameters—A, B, and C—are being investigated. These parameters will have a low level (minimum) and a high level (maximum). The design used in this work has two levels and belongs to a group of designs known as 2^k factorial experiments (Walpole et al., 2012) where k is the number of parameters being investigated. In ED, the parameter levels are more conveniently dealt with using dimensionless coded variables, i.e., -1 for low, 0 for middle, and +1 for high settings (Anderson and Whitcomb, 2000; Myers and Montgomery, 2002). The parameter combinations are therefore the designed experiment or simulation runs required by the design. The two-level (+1,-1), three-parameter (A, B, and C) full factorial design requires 2^3 or 8 simulation runs. This is shown in Figure 1.



Run	A	B	C
1	-1	-1	-1
2	+1	-1	-1
3	-1	+1	-1
4	+1	+1	-1
5	-1	-1	+1
6	+1	-1	+1
7	-1	+1	+1
8	+1	+1	+1

Figure 1. Design points (experiments) and the parameter combinations for each run on a full factorial experimental design.

Run 1 describes a reservoir simulation where the total flow is determined while all three parameters are at their low levels. This experiment or design point is represented as a corner point in the design cube plot. Once the simulation runs for all corner points are done and the total flow for each simulation is determined, the relationship between the total flow and the three parameters may be estimated by a response polynomial (also termed a response surface).

$$total\ flow = \beta_0 + \beta_1 A + \beta_2 B + \beta_3 C + \beta_4 AB + \beta_5 AC + \beta_6 BC + \beta_7 ABC \tag{1}$$

The β are the coefficients while the tested parameters are the variables in the response polynomial. The polynomial describes the behavior of the response within the design cube or parameter space investigated, including the interaction effects (AB, AC, BC, ABC) between parameters.

1.1 Experimental Design in Reservoir Simulation

While its origins are in the field of agriculture and clinical studies, experimental design applications has extended into simulations and computer experiments (Santner et al., 2003). Application of experimental design in oil and gas reservoir simulations began in the 1990's (Damsleth et al., 1992) and developed into more detailed frameworks and workflows (Friedmann et al., 2003; White and Royer, 2003; Yeten et al., 2005; Amudo et al., 2008). A summary of these workflows is presented in Figure 2.

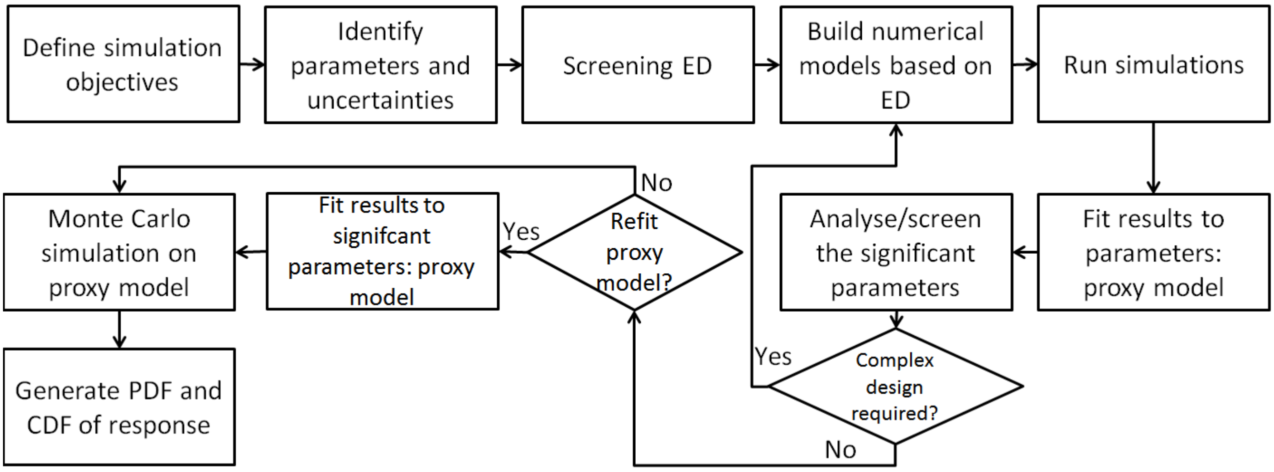


Figure 2. Experimental design and response surface workflow in reservoir simulation and probabilistic response generation.

Designed experiments have been successfully used in the uncertainty analysis of reservoir simulation results and resource evaluation. In actual simulations, the large number of input parameters and parameter levels require a large number of experiments: with 10 parameters at two levels, a full factorial design will be 210 or 1,024 experiments; if the design is done at three levels (low, mid, and high), the total number of experiments will be close to 60,000. A simulation run in a full-field geothermal reservoir model can range from a few minutes to a few several hours depending on the complexity of the model. With more design parameters and levels, the required number of runs becomes prohibitively time consuming.

With an appropriate experimental design, maximum information can be gathered from a smaller number of simulation runs. Fractional factorial designs run only a fraction (1/2, 1/4, 1/8) of the full factorial design (Walpole et al., 2012). Screening designs are effective in identifying the key parameters that affect the response. An example screening design is the Plackett-Burman design. There are higher-level and more complex designs used especially when optimization is the objective of the reservoir simulation. Examples of more complex designs are the Central Composite Design (CCD) and Box-Behnken design, with results that fit at least a quadratic polynomial to enable optimization (Myers and Montgomery, 2002). Comparison of common experimental designs used in reservoir simulation studies has been done by Yeten et al. (2005).

1.2 Volumetric Methods

Probabilistic resource assessments have been done by assigning probabilistic distribution functions to the parameters of the volumetric equations (Grant and Mahon, 1995; Parini et al., 1995; Parini and Riedel, 2000; Sanyal and Sarmiento, 2005; Williams et al., 2008; AGRCC, 2010; Garg and Combs, 2010/2011; Onur et al., 2010). The volumetric equation is either a "heat in place" (stored heat) or a mass in place (MIP) estimate.

1.2.1 USGS Volumetric Heat in Place Methods

The United States Geological Society (USGS) has used a volumetric stored heat method developed by Nathenson (1975), White and Williams (1975), Muffler and Cataldi, (1978), and Muffler (1979) to estimate the geothermal resources in the United States. The resource assessment is based on the total stored energy or "heat in place' contained in a volume of geothermal system:

$$q_R = \rho C V (T_R - T_0) \tag{2}$$

where ρC is the volumetric specific heat (thermal capacity) of the rock, V is the volume of the reservoir, T_R is the reservoir temperature, and T_0 is a reference or a dead state temperature. The energy extracted at the wellhead is given by:

$$q_{WH} = m_{WH}(h_{WH} - h_0) \tag{3}$$

where m_{WH} is the mass that can be extracted at the wellhead, h_{WH} is the enthalpy of the fluid produced at wellhead, and h_0 is the enthalpy at a reference temperature. The ratio between the extractable thermal energy and the total volumetric thermal energy in the reservoir is known as the recovery factor, R_g, given by:

$$R_g = \frac{q_{WH}}{q_R} \tag{4}$$

The mass of fluid produced at the wellhead is given by substituting equation (3) into equation (4)

$$m_{WH} = \frac{R_g q_R}{(h_{WH} - h_0)} \tag{5}$$

From this available thermal energy at the wellhead, the exergy, E, defined by DiPippo (2005) or the maximum available work (Muffler, 1979) is given by

$$E = m_{WH}[h_{WH} - h_0 - T_0(s_{WH} - s_0)] \tag{6}$$

where s_{WH} is the entropy of the fluid produced at wellhead and s_0 is the entropy at a reference temperature (T_0) set at 15 or 40°C in literature (Williams et al. 2008). From the exergy or work available over a period of time (plant life), the electric energy generation rate, $\dot{W}_e$, is based on a utilization efficiency, η_u, and is given by:

$$\dot{W}_e = \dot{E}\eta_u \tag{7}$$

Williams et al. (2008) notes that η_u is 0.4 for systems above 175 °C. This set of equations is collectively referred to in this work as the "USGS volumetric stored heat method."

1.2.2 AGRCC Stored Heat Method

The volumetric stored heat equation is described in the Australian Geothermal Code (Australian Geothermal Reporting Code Committee AGRCC, 2010) by the following equation:

$$H_{th} = V\left[\rho_r C_r(1-\varphi)(T_R - T_{\mathrm{f}}) + \varphi\rho_{sR}(1 - S_{w)}(h_{sR} - h_{wR}) + \varphi\rho_{wR}S_w(h_{wR} - h_{w\mathrm{f}})\right] \tag{8}$$

where H_{th} is the theoretical maximum quantity of useful heat, V is the volume of the reservoir in m^3, the subscripts r and w represent the rock and water component, ρ is the density in kg/m^3 , C is the specific heat capacity in J/kg-K, φ is the connected porosity or the void space filled with geothermal fluid, T_R is initial reservoir temperature, T_f is the reservoir final temperature at which point the reservoir is considered depleted, S_w is the water saturation, h_{sR} and h_{wR} are the steam and water enthalpies (kJ/kg) at the reservoir temperature, and h_{wf} is the water enthalpy at the reservoir final temperature (kJ/kg).

The electrical energy derived from the conversion of this theoretical useful heat is given by:

$$W_e = \frac{H_{th} R_f \eta_c}{LF} \tag{9}$$

where W_e is the power plant capacity in kWe, H_{th} is the theoretical available heat (kJ), R_f is the recovery factor, η_c is the conversion efficiency, L is the power plant life in seconds, and F is the power plant load factor. This set of equations (8-9) is collectively referred to in this work as the "AGRCC (2010) volumetric stored heat method."

1.2.3 Volumetric Mass In Place (MIP) Method

Another volumetric method presented by Parini and Riedel (2000) uses the total mass in place (MIP) instead of stored heat.

$$MIP = V\varphi\rho(T) \tag{10}$$

where V is the volume of the reservoir, φ is the average total porosity, and $\rho(T)$ is the fluid density at the average reservoir temperature, T. The electrical generating capacity of the system, P, is given by

$$P = \frac{MIP \times R_m}{UF \times CF \times H} \tag{11}$$

where R_m is the mass recovery factor defined as total steam produced over the initial mass in place, UF is the steam usage factor at kg/kWh, CF is the capacity factor or power plant load factor, and H is the project life in hours. Parini and Riedel (2000) studied the relationship between mass recovery factor and 10 uncertain parameters using numerical simulation.

The USGS and AGRCC methods are similar in describing the volumetric stored energy in the system but differ in converting the recovered thermal energy into electrical power. Williams et al. (2008) provided an updated range of thermal recovery factors, R_g, used by the USGS from one with a triangular probability distribution (0 to 0.5, 0.25 most-likely value) to one with a uniform probability distribution and narrowed the range down to 0.08 to 0.2 for fracture dominated reservoirs. They observed that the variation in thermal recovery may be influenced by how fracture permeability affects reservoir flow patterns and consequently, effective heat mining. Since the permeability pattern is not known prior to production, a uniform distribution of a range of recovery factors was recommended. The MIP method in this section uses the mass recovery factor's relationship with the parameters that influence the production of fluid at the wellhead, investigated through numerical modeling. Since this is a mass recovery factor, it is numerically higher than the thermal recovery factor. Atkinson (2012) noted that the MIP method can be used to estimate proved reserves with reasonable certainty because of this clearer basis for a recovery factor.

1.3 Numerical simulation

The use of numerical simulations for resource assessment is gaining ground, especially at a fairly advanced development stage defined by the AGRCC (2010) as the delineation stage: exploration wells have been drilled and a decision point has been reached to do additional drilling or surface facility construction. Grant (2000) argued for the superiority of numerical simulations in evaluating the size of a geothermal development.

A numerical simulation result is deterministic and while generating probabilistic results from it is possible, it is resource intensive. A process described by Atkinson (2012) involves building numerous equi-probable reservoir models with satisfactory history match and running the models in forecast mode. While the use of numerical simulations with varying key parameters that affect field production has been done on a base model (Parini and Riedel, 2000), using a set of equi-probable alternative numerical models, calibrated against alternative conceptual model realizations of a greenfield geothermal system has not been found in literature.

Acuña et al. (2002) built and calibrated alternative full-field reservoir simulation models for an operating field with the most-likely, pessimistic, and optimistic models and responses generated. The large models used by Acuña et al. (2002) were reduced to proxy models or polynomials representing the model response, similar to a response surface in the ED and RSM methodology. In both cases, it is difficult to independently verify the results of these numerical simulations.

The AGRCC (2010) and Atkinson (2012) have noted that resource assessment results should be independently verifiable. An experimental design process can facilitate resource assessment using numerical simulations. Since the design is known, the process and the basis for assessed resource capacity can be verified. The ED and RSM method was applied by Hoang et al. (2000) to a resource optimization study in the Darajat geothermal field. A green-field geothermal resource assessment using this method is part of an ongoing work by Quinao and Zarrouk (2014).

2. PROBABILISTIC RESOURCE ASSESSMENT METHODS APPLIED TO A SIMPLE GEOTHERMAL SYSTEM

The geothermal system used in the succeeding analyses was originally described and analyzed by Parini and Riedel (2000) and is shown in Figure 3. The probabilistic results of their combined volumetric and numerical simulations are 175 MW (P10), 290 MW (P50), and 460 MW (P90).

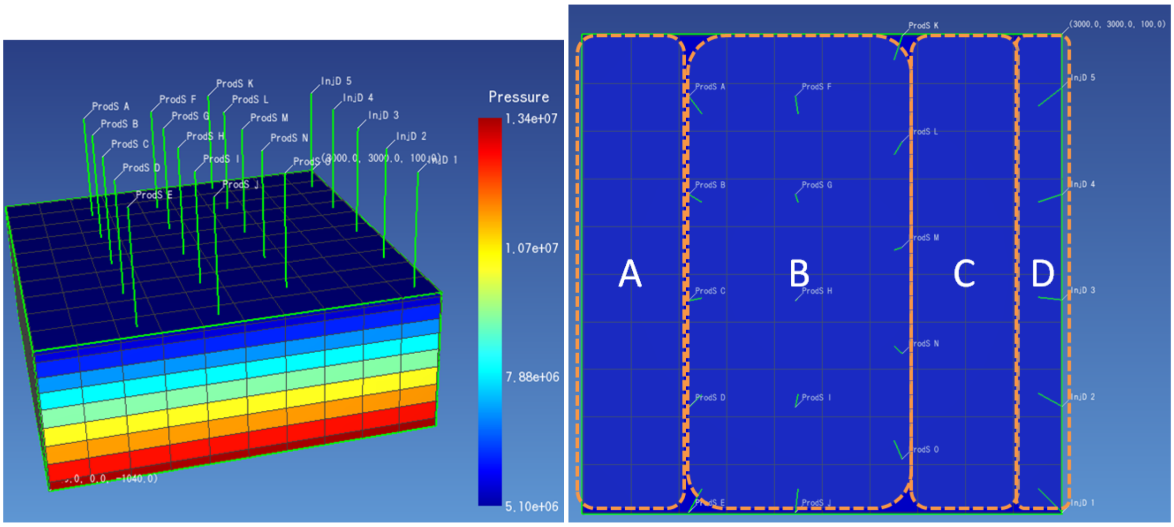


Figure 3. Model geometry showing the modeled reservoir volume, the production wells in sector B, the injection wells (D), an injection buffer area (C), and an inaccessible area (A). The surface elevation (not shown) is at 1000 m ASL and the modeled reservoir thickness is from 100 m ASL down to -1040 m ASL.

The parameters that describe the system and are used in the volumetric resource assessments are listed in Table 1. Note that the range of values for the Monte Carlo simulation is also listed as low, mid, and high. The parameters with probability distribution functions are limited to the same parameters tested in the numerical simulation part.

The succeeding resource assessments are based on the following assumptions for easier comparison:

- The power cycle is a single flash steam turbine with a separator pressure at 9 bar abs.
- The reference temperature in the reservoir (the final state) is 175.36 °C, the liquid water saturation temperature at separation pressure.
- The ambient temperature for the exergy analysis is set at 15 °C and not at the condenser temperature.
- The uncertain parameters in the Monte Carlo simulations are limited to the reservoir parameters tested in the ED and RSM method. All other parameters were set constant.

Table 1. Parameters used in the volumetric probabilistic analyses. The shaded values represent the subsurface parameters.

	Parameters	Low	Mid	High	Distribution
A	Area, km^2	--	9	--	N.A.
h	Thickness, km	--	1.14	--	N.A.
φ	Average total porosity	0.05	0.08	0.1	Triangular
T_R	Reservoir Temperature, °C	250	265	280	Triangular
T_f	Reservoir Final Temp, °C	--	175.36	--	N.A.
T_0	Reservoir Reference Temp, °C	--	175.36	--	N.A.
T_0	Exergy Reference Temp, °C	--	15	--	N.A.
C_r	Rock heat capacity, J/kg K	--	1000	--	N.A.
ρ_r	Rock density, kg/m^3	--	2600	--	N.A.
S_w	Relative water saturation	--	1.0	--	N.A.
R_g	Thermal recovery factor	0.08	0.1	0.2	Uniform
	Power generation		Single Flash		
	Separator pressure, bar abs		9		
F, CF	Plant load factor[1]		0.85		
L, H	Project life, years		30		
η_c	Conversion efficiency[1]		0.12		
η_u	Utilization efficiency[2]		0.4		

[1]Only used for the AGRCC volumetric estimate. Conversion efficiency is based on a review by Zarrouk and Moon (2014). [2]Utilization efficiency as described by Williams et al. (2008), only used for the USGS volumetric estimate.

2.1 Probabilistic Numerical Simulation through Experimental Design and Response Surface Methods

Results of this analysis have been presented by Quinao and Zarrouk (2014) and a shorter summary is presented here for reference.

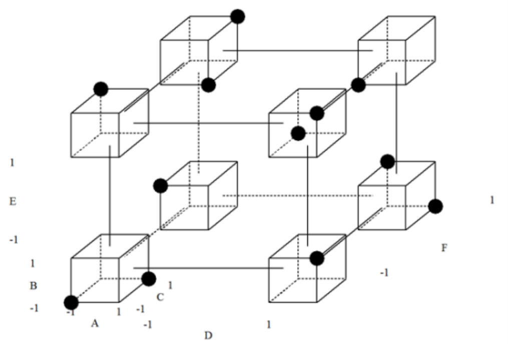
Following the workflow in Figure 2, six parameters were investigated: reservoir temperature, porosity, fracture permeability, average fracture spacing, well feedzone depth, and boundary conditions. Note that the range of parameter values limits the results to within the values identified. The parameters are summarized in Table 2.

Table 2. Reference model parameters chosen for the Experimental Design.

Parameter	Low	Mid	High
Reservoir Temperature, °C	250	265	280
Matrix porosity	0.05	0.08	0.1
Fracture permeability, mD	10	60	100
Average fracture spacing (3D)	2 (approx. single porosity)	30	100
Well feedzone depth	Shallow (1350 m)	--	Deep (1900 m)
Boundary conditions	Close	--	Open (150°C lateral recharge)

A two-level (high and low) Plackett-Burman (PB) design was chosen to identify the main parameters that affect system's 30-yr power capacity. The experimental design generated from Minitab™ is shown in Figure 4.

Plackett-Burman Design: 2 Levels and 6 Parameters



Std Order	Temperature	Porosity	Permeability	Frac Spacing	Well Depth	Boundary
6	+1	+1	+1	-1	deep	open
11	-1	+1	-1	-1	shallow	open
3	-1	+1	+1	-1	deep	closed
5	1	+1	-1	+1	deep	closed
9	-1	-1	-1	+1	deep	open
7	-1	+1	+1	+1	shallow	open
12	-1	-1	-1	-1	shallow	closed
2	+1	+1	-1	+1	shallow	closed
8	-1	-1	+1	+1	deep	closed
1	+1	-1	+1	-1	shallow	closed
4	+1	-1	+1	+1	shallow	open
10	+1	-1	-1	-1	deep	open

Figure 4. Plackett-Burman design for six parameters with a total number of 12 experiments.

2.1.1 Numerical Simulation Models

The 12 numerical simulation models were built using the TOUGH2 geothermal reservoir simulator. The Equation of State (EOS) module used was EOS1 (non-isothermal water). A three-dimensional dual-porosity formulation was used with three (3) multiple interacting continua (MINC) layers. Other model details are summarized in Table 3.

2.1.2 Model Geometry

The surface area of the model is 9 km^2 (3 km by 3 km) divided into 12 blocks along the x and y model dimensions. The reservoir thickness is 1.14 km divided into 10 layers with thinner upper layers to capture the phase changes. The outermost lateral blocks are thin blocks used to implement fixed states. There are 1440 blocks in this simple reservoir model. . The surface area was divided into four main regions (labelled A to D) to represent a development strategy (see below and Figure 5):

1. 20% - A: No drilling/no access, e.g., national park, inaccessible terrain, etc.
2. 50% - B: Production area
3. 20% - C: Production-injection buffer, and
4. 10% - D: Deep injection

Table 3: General parameters in all numerical model runs.

Model parameter	Value	Unit
Reservoir volume	10.26	km^3
Number of blocks	1440	blocks
Initial reservoir pressure	$P_{saturation}$ + 10	bar
Rock density	2600	kg/m^3
Rock wet heat conductivity	2.2	W/m-C
Rock heat capacity	1	kJ/kg-C
Relative Permeability	Grant's curves	
Residual liquid saturation	0.3	
Residual gas saturation	0.05	
Capillary pressure function	Linear function	
CP_{max} – CP(1)	1.0E6	
A – CP(2)	0.25	
B – CP(3)	0.4	
Production wells	15	wells
Minimum wellhead P	11	bar abs
Deep injection wells	5	wells
Total mass production	555	kg/s
Total injection rate	~416	kg/s
Separator P	9	bar abs
Steam usage rate	7	kg/kW
Power capacity years	30	years

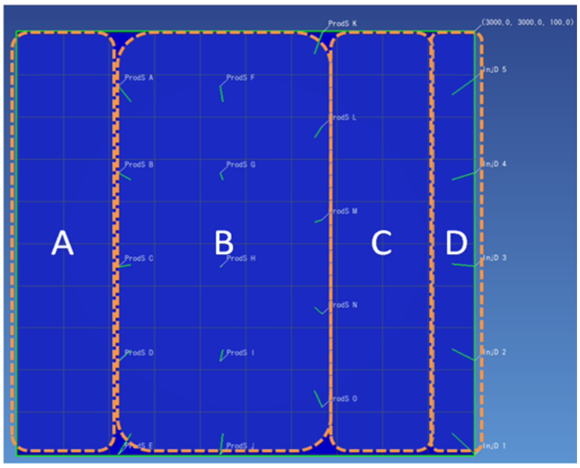


Figure 5: The different regions of the reservoir representing a development strategy.

Five deep injection wells were used with 15 production wells distributed around the production area. The shallow wells tap the reservoir at -350 m above sea level (mASL) while the deep wells tap the reservoir at -900 mASL. In the simulation runs that have "open" boundary condition settings, a fixed state at -590 mASL is implemented by thin blocks around the four lateral sides of the model, providing recharge to the reservoir at 150°C and constant initial reservoir pressure in the thin blocks.

2.1.3 Reservoir Simulation Runs and Proxy Model

The reservoir simulations were run with a constant total mass production from 15 wells injecting 75% of the mass produced into the five deep injection wells. The enthalpy of the injected water is at 9 bar abs separation pressure. Simulations were performed until a production well was unable to produce at the minimum wellhead pressure. The total steam generated is converted into electrical energy using

$$MW_e = \frac{\sum_{i=1}^{15} \frac{x_i \times \dot{m}_{WH}}{UF} \times t_{sim}}{L} \quad (12)$$

where x_i is the steam fraction based on the well's enthalpy and separation pressure, t_{sim} is the simulation time where one well ceases to flow, UF is the steam usage factor at 7.5 kg/kWh, and L is the project life at 30 years.

The capacities are therefore conservative as they are estimated only up to when the total mass production cannot be supported by the 15 production wells. The results are summarized in Table 4.

Table 4: Designed simulation runs and 30-yr power capacity results.

Std Order	Temperature	Porosity	Permeability	Frac Spacing	Well Depth	Boundary	Power Capacity, MWe
6	+1	+1	+1	-1	deep	Open	**53**
11	-1	+1	-1	-1	shallow	Open	**65**
3	-1	+1	+1	-1	deep	Closed	**59**
5	1	+1	-1	+1	deep	Closed	**129**
9	-1	-1	-1	+1	deep	Open	**48**
7	-1	+1	+1	+1	shallow	Open	**213**
12	-1	-1	-1	-1	shallow	Closed	**39**
2	+1	+1	-1	+1	shallow	Closed	**125**
8	-1	-1	+1	+1	deep	Closed	**89**
1	+1	-1	+1	-1	shallow	Closed	**255**
4	+1	-1	+1	+1	shallow	Open	**361**
10	+1	-1	-1	-1	deep	Open	**97**

The PB design results are approximated by a first-order polynomial shown as

$$Power\ Capacity = 127.84 + 42.25 \times A - 20.46 \times B + 43.88 \times C + 33.12 \times D - 48.64 \times E + 11.76 \times F \qquad (13)$$

where A is reservoir temperature, B is matrix porosity, C is fracture permeability, D is average fracture spacing, E is well feed zone depth, and F is boundary condition. Note that choosing the PB experimental design limits the response surface to a first-order polynomial.

When the proxy model is refitted to include only the significant parameters, the polynomial becomes:

$$Power\ Capacity = 127.84 + 42.25 \times A + 43.8871 \times C - 48.64 \times E \qquad (14)$$

2.1.4 Monte Carlo Simulation on the Reservoir Simulation Proxy Model

A probabilistic resource assessment was done via Monte Carlo simulation on the proxy model given in equations (13) and (14). The probability distributions of the polynomial variables were applied to the coded low, mid, and high values. Using both the refitted (Equation 14) and full proxy models (Equation 13), the cumulative distribution function for the resource is shown in Figure 6. Note that the P50 values are almost the same while the power capacity range and standard deviation is larger when more factors are included in the proxy model.

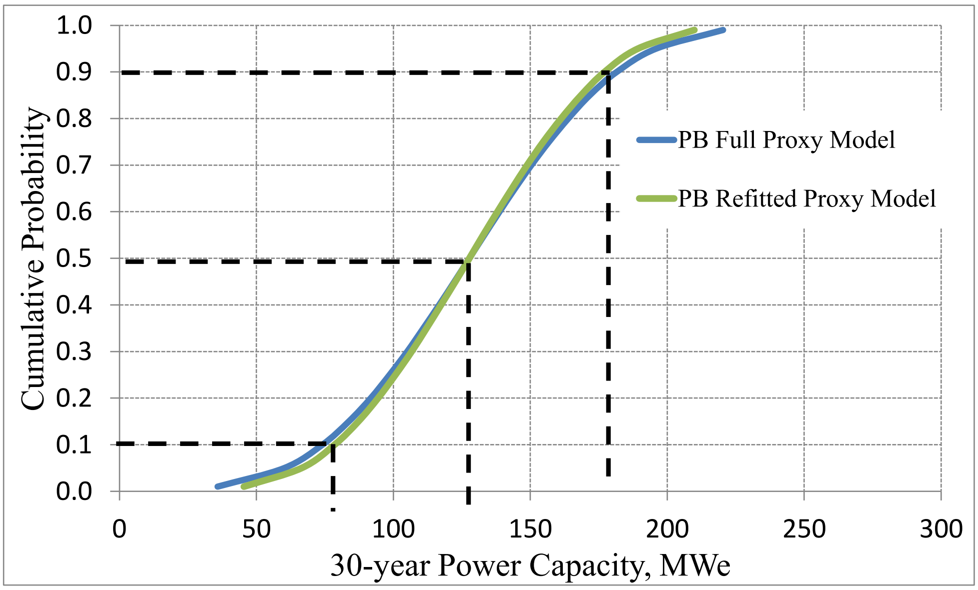


Figure 6: Cumulative distribution functions with P10, P50, and P90 indicated.

2.2 Probabilistic Assessment using the USGS Volumetric Stored Heat Method

To illustrate, the method described in Section 1.2.1 is applied to the system described in Table 1, we estimate the total reservoir heat in place at

$$q_R = V[\rho_r C_r(1-\varphi) + \rho_w C_w \varphi](T_R - T_0) = 2.487 \times 10^{18}\text{Joules} \tag{15}$$

When applying a thermal recovery factor of 10% (Table 1), we arrive at the energy recovered at the wellhead

$$q_{WH} = R_g q_R = 2.487 \times 10^{17}\text{Joules} \tag{16}$$

The exergy estimate is given by equation (5) where the reference temperature, T_0, of the maximum available work from the wellhead thermal energy is 15°C and the work required to lift the fluid from the reservoir to the wellhead is neglected.

$$E = m_{WH}[h_{WH} - h_0 - T_0(s_{WH} - s_0)] = 1.210 \times 10^{17}\text{Joules} \tag{17}$$

Applying a utilization efficiency of 0.4, the electrical generating capacity of the system at 30 years is given by Equation (6)

$$\dot{W}_e = \dot{E}\eta_u = 51.14\text{ MWe} \tag{18}$$

Garg and Combs (2011) suggested that the USGS method should consider specific power cycles when estimating the utilization efficiency. Applying this to our single flash system at 9 bar abs a separation pressure, the exergy is evaluated at the saturated steam conditions and the mass is the steam entering the turbine. Turbo-generator efficiency of 70% is applied as recommended by Garg and Combs (2011).

$$E = m_s\left[h_{sep} - h_0 - T_0\left(s_{sep} - s_0\right)\right] = 4.040 \times 10^{16}\text{Joules} \tag{19}$$

$$\dot{W}_e = \dot{E}\eta_u = 29.87\text{ MWe} \tag{20}$$

In both of these estimates, the total average porosity, reservoir temperature and recovery factor were randomly sampled in a Monte Carlo simulation to derive a probabilistic resource assessment. The results are shown in Figure 7.

2.3 Probabilistic Assessment Using the AGRCC Volumetric Stored Heat Method

Using equations (7) and (8), the theoretical maximum quantity of useful heat is given by

$$H_{th} = V\left[\rho_r C_r(1-\varphi)(T_R - T_f) + \varphi\rho_s(1 - S_{w)}(h_{sR} - h_{wR}) + \varphi\rho_w S_w(h_{wR} - h_{wf})\right] = 2.466 \times 10^{18}\text{ Joules} \tag{21}$$

The electrical energy is estimated using an average conversion efficiency of 12% (Zarrouk and Moon, 2014). This results in a lower power capacity:

$$W_e = \frac{H_{th} R_f \eta_c}{LF} = 36.8\text{ MWe} \tag{22}$$

Similar to the previous estimates, a probabilistic analysis was done through a Monte Carlo simulation where the uncertainties of the porosity, recovery factor, and reservoir temperature are considered. The results are shown in Figure 7.

2.3 Probabilistic Assessment Using MIP Method

The equations for this type of volumetric resource assessment are described in Equations (9) and (10). The total mass in place is

$$MIP = V\varphi\rho(T) = 6.369 \times 10^{11}\text{ kg} \tag{23}$$

The power capacity is given by

$$P = \frac{MIP \times R_m}{UF \times CF \times H} = 177.9\text{ MWe} \tag{24}$$

where some of the parameters missing from Table 1 are listed below in Table 5.

The range of mass recovery factors has been estimated from the main effects plot in Parini and Riedel (2000) and a triangular probability distribution was chosen. The main effects plots between the mass recovery factors and around ten parameters were based on numerical simulation results.

Table 5: Additional parameters MIP method

Parameters	Low	Mid	High	Distribution
Recovery factor, (volumetric/numerical)	0.205	0.47	0.75	Triangular
Steam usage rate (UF), kg steam/kW	--	7.5	--	N.A.

The probabilistic resource analysis using this method was also done by Monte Carlo simulation (Figure 7). The result is different from the one desrcribed by Parini and Riedel (2000) because the parameters used in this analysis were limited to the parameters tested in the designed simulation experiments.

Table 6: Summary results of the illustrated volumetric methods showing the parameters that were set constant at each method.

Volumetric Methods	T_R, °C	T_f, $T_{0(USGS)}$, °C	q_R, H_{th}*, Joules and MIP**	R_g, R_f*, R_m**	$T_{0(exergy)}$, °C	E, *$E_{turbine}$, Joules	η_u, *$\eta_{u(turbine)}$, **η_c	MW_e
USGS (Williams et al. 2008)	265	175.36	2.49×10^{18}	0.1	15	1.21×10^{17}	0.4	134.4
USGS (Garg & Combs, 2011)	265	175.36	2.49×10^{18}	0.1	15	4.04×10^{16}	*0.7	78.5
AGRCC (2010)	265	175.36	*2.47×10^{18}	*0.1	N.A.	N.A.	**0.12	32.8
MIP (Parini & Riedel)	265	N.A.	**6.37×10^{11} kg	**0.47	N.A.	N.A.	7.5 kg_s/kWh	177.9

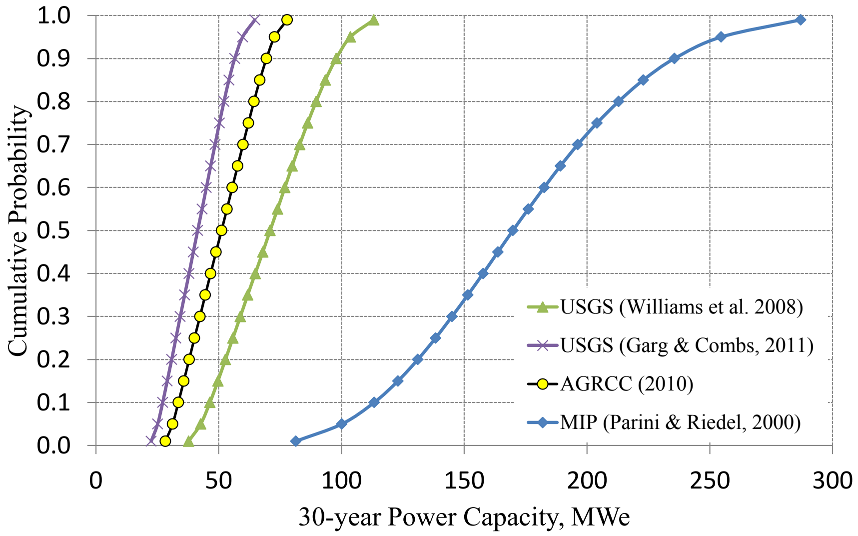


Figure 7: Probabilistic volumetric resource assessment results for the simplified geothermal system described.

The simple comparisons of the volumetric methods in Table 6 and Figure 7 show that:

1. the results are affected by the difference between the utilization efficiency, which is based on exergy used in the USGS (Williams et al. 2008) method, and the conversion efficiency used in the AGRCC (2010) method, which is based on total produced thermal power (with reference to a liquid enthalpy of zero at the triple point of water “0.01 ºC”); and
2. the result of the MIP method is significantly different from the stored heat volumetric methods. The MIP method effectively assumes that for R_m = 1.0, the original fluid mass in-place in the reservoir is produced as steam.

3. DISCUSSION

The various probabilistic resource assessment results included in this study are presented in Figure 8.

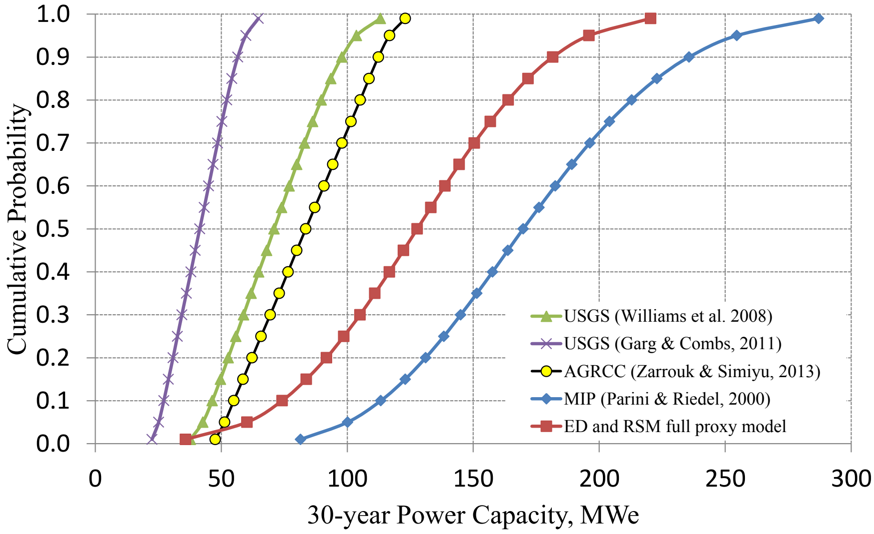


Figure 8: Probabilistic assessment results using volumetric and numerical simulation methods (with ED and RSM).

In Figure 8, the modified stored heat equation presented by Zarrouk and Simiyu (2013) is applied to the AGRCC (2010) estimate:

$$W_e = \left(\frac{H_{th}}{L} + nq_{th}\right)\frac{R_f\eta_c}{F} = 59.9 \text{ MWe} \qquad (25)$$

where q_{th} is the thermal energy input of recharge or injection and n is a constant between 1 and $1/R_f$. To bring the estimate closer to the numerical simulation results, a q_{th} = 163.8 MW_{th} (the injected mass flow heating up from 175.36 to 265°C) and $n = 1/R_f = 10$ were used in equation (25). This represents 100% recovery of an injection-production recharge cycle in addition to the recovery from the original volumetric stored heat. To match the simulation results, n has to be greater than $1/R_f$ or the recovery factor has to be higher.

Parameters that can be standardized across the methods were applied, e.g. using a uniformly distributed thermal recovery factor from 0.08 to 0.2 in the volumetric stored heat method. This resulted in similar results of recovered thermal energy at the wellhead. The variation in the results between the USGS (Williams et al. 2008), USGS (Garg & Combs, 2011), and the AGRCC (2010; Zarrouk and Simiyu, 2013) stored heat methods are mainly on conversion and/or utilization efficiency.

The MIP and the ED and RSM results are both based on minimum capacity to produce at a given wellhead condition. Because of this, the parameters that strongly affect the numerical model results include permeability and well depth (production depth)—factors that are lumped together inside the thermal recovery factor, R_g or R_f in the stored heat assessment. For systems with good permeability and strong pressure support, the thermal recovery factor will be higher. For example, one of the simulation experiments (closed boundary, deep wells, 265°C reservoir temperature) resulted in a 30-year power capacity of 89 MWe. The total thermal recovery was 9.85×10^{17} Joules representing a thermal recovery factor of 40-45% with injection providing additional pressure support and help in sweeping the heat to the production wells.

Conversion for the MIP and the numerical simulations using ED and RSM were set at 7.5 kg (steam)/kWh. Verifying this estimate with the exergy analysis used by Garg and Combs (2011) for single flash units, the use of this consumption rate underestimates the result by 20% at 15°C reference temperature but is almost identical at a 40°C reference/condenser temperature.

The geothermal system under investigation has a relatively high final temperature, set at the injected fluid temperature (175.36°C, separated brine at 9 bar abs) due mainly to the power cycle used in converting the thermal energy into electric energy. However, this is consistent with values used in the AGRCC method (2010) . The injectate and the recharge provide pressure support and fluids that may help in sweeping the heat from the system, increasing the recovery factor. This is the case for the open boundary condition in the numerical simulation where marginal fluid at 150°C and injectate at 175.36°C flow into the system providing pressure support and when effectively heated up, produced at surface (Figure 9).

These results support an earlier observation that even with a standardized recovery factor, the volumetric methods require clearer definition regarding the power capacity described and the reference points they are based on, i.e. this assessment estimates available power capacity at a reservoir reference temperature of 175.36°C, a conversion efficiency reference temperature at 15°C using a single flash plant at 9 bar abs. This clarity in flow production capacity is what makes a numerical simulation more desirable and the same can be said for the MIP method: Either the field will be able to supply a 9 bar abs flash plant and produce 50 MWe or not. The ED and RSM method enables us to use numerical modeling and honor the existing uncertainties.

A very broad thermal energy estimate is more generic and useful in comparing resources across different geothermal systems but a clearer set of criteria is required if thermal energy is to be translated or booked as an electric power capacity.

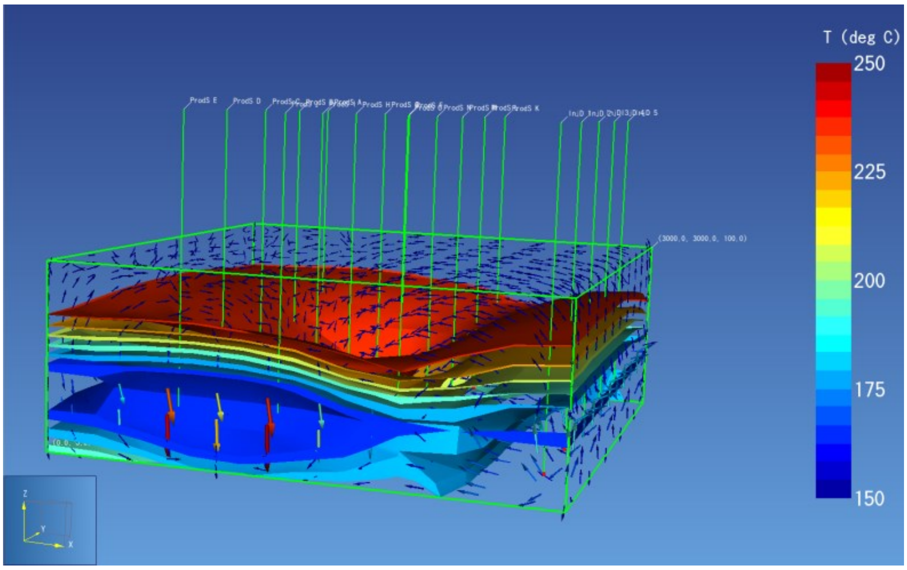


Figure 9: Temperature surfaces of the modeled system during one of the simulation runs at open boundary conditions and 75% injection of separated brine (9 bar abs).

5. CONCLUSIONS AND RECOMMENDATIONS

From the results of the study presented and discussed, we conclude that

- the ED and RSM methods can be used to build a verifiable probabilistic resource assessment using numerical simulation; and
- the existing volumetric stored heat methods for resource assessment still result in variations even with a similar recovery factor due to ambiguity in reference/final temperatures and energy conversion processes.

We recommend that when doing a resource assessment

- the conversion/utilization efficiency is carefully applied;
- the assumptions are clearly stated, recognizing the risk of it being overly specific; and
- production-based (numerical simulation or mass in place) methods are considered over volumetric thermal methods to provide better clarity in estimating power capacity.

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